PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION

ID #9029
RESOLUTION E-4298
December 17, 2009

R E S O L U T I O N

Resolution E-4298.

PROPOSED OUTCOME: This Resolution formally adopts the 2009 Market Price Referent values for use in the 2009 Renewables Portfolio Standard solicitations. This Resolution is made on the Commission's own motion.

ESTIMATED COST: None

SUMMARY

2009 Market Price Referent values have been calculated for use in the 2009 Renewables Portfolio Standard solicitations.

This Resolution formally adopts the 2009 Market Price Referent (MPR) values for use in the 2009 Renewables Portfolio Standard (RPS) solicitations. The 2009 MPR values were calculated using the methodology, model and inputs adopted by this Commission. This Resolution also adopts MPR values to serve as the price reasonableness benchmark for RPS contracts with delivery terms of at least four years but less than 10 years. This Resolution is made on the Commission's own motion.

Table 1: 2009 MPR values for long-term (10 - 25 year) RPS contracts

Adopted 2009 Market Price Referents[1] (Nominal - dollars/kWh)				
Contract Start Date	**10-Year**	**15-Year**	**20-Year**	**25-Year**
2010	0.08448	0.09066	0.09674	0.10020
2011	0.08843	0.09465	0.10098	0.10442
2012	0.09208	0.09852	0.10507	0.10852
2013	0.09543	0.10223	0.10898	0.11245
2014	0.09872	0.10593	0.11286	0.11636
2015	0.10168	0.10944	0.11647	0.12002
2016	0.10488	0.11313	0.12020	0.12378
2017	0.10834	0.11695	0.12404	0.12766
2018	0.11204	0.12090	0.12800	0.13165
2019	0.11598	0.12499	0.13209	0.13575
2020	0.12018	0.12922	0.13630	0.13994
2021	0.12465	0.13359	0.14064	0.14424

[1] Using 2010 as the base year, Staff calculates MPRs for 2010-2021 that reflect different project online dates. MPRs for short-term contracts are provided in Appendix A. The 2009 MPR model is available at: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

BACKGROUND

Overview of RPS Program

The California RPS Program was established by Senate Bill (SB) 1078, and has been subsequently modified by SB 107 and SB 1036.[2] The RPS program is codified in Public Utilities Code Sections 399.11-399.20.[3] The RPS program administered by the Commission requires each utility to increase its total procurement of eligible renewable energy resources by at least one percent of retail sales per year so that 20 percent of the utility's retail sales are procured from eligible renewable energy resources no later than December 31, 2010.[4]

Additional background information about the Commission's RPS Program, including links to relevant laws and Commission decisions, is available at http://www.cpuc.ca.gov/PUC/energy/Renewables/overview.htm and http://www.cpuc.ca.gov/PUC/energy/Renewables/decisions.htm.

The MPR is an important element in the RPS procurement process

RPS program cost containment

Pursuant to Legislation, the MPR establishes the basis for the use of above-market funds (AMFs) which set a limitation on RPS procurement costs that are above the MPR and are awarded by the Commission pursuant to SB 1036.[5, 6] Through this function, the MPR sets a limit on the procurement obligations of

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[2] SB 1078 (Sher, Chapter 516, Statutes of 2002); SB 107 (Simitian, Chapter 464, Statutes of 2006); SB 1036 (Perata, Chapter 685, Statutes of 2007)

[3] All further references to sections refer to Public Utilities Code unless otherwise specified.

[4] Section 399.15(b)(1).

[5] The original method for funding above-market costs was the use of Supplemental Energy Payments (SEPs), administered by the California Energy Commission. The SEP program was eliminated by SB 1036 (Perata), Stats. 2007, ch. 685.

[6] In order to carry out this function, the Commission in D.04-06-015 concluded that the contract price should be compared to the MPR on a net present value basis as calculated over the entire contract term.

retail sellers under the RPS program.[7] That is, if the amount of AMFs available to an electrical corporation is insufficient to support the total costs expended above the MPR, then the Commission shall allow an electrical corporation to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be procured with available AMFs. However, a utility can voluntarily decide to procure above-MPR RPS contracts once the cost limitation has been exhausted.[8]

RPS contract cost reasonableness assessment

The Commission must find that the costs of each RPS contract are reasonable before it approves a utility power purchase agreement for RPS-eligible energy. The Commission compares the levelized all-in costs of each long-term RPS contract (greater than 10 years), on a $/megawatt hour basis, to the MPR to evaluate the reasonableness of RPS contract costs. The Commission's cost reasonableness assessment of RPS contracts also includes a comparison of a proposed contract to other RPS procurement opportunities from recent RPS solicitations, as well as, Commission approved RPS contracts.

In D.09-06-050, the Commission established a methodology for calculating a price reasonableness benchmark for short-term RPS contracts, that is, contracts that are less than 10-year commitments. Pursuant to D.09-06-050, the MPR methodology is used to calculate MPR values to be compared with the price of RPS contracts that have duration of at least four years but less than 10 years. (Refer to Appendix A.)

MPR procedural history

The Commission set the initial parameters for the MPR in D.03-06-071. The method for calculating the MPR was first developed in D.04-06-015. In D.04-06-015, the Commission clarified "what the MPR is not: it does not represent the cost, capacity or output profile of a specific type of renewable generation technology. . . [T]he MPR is to represent the presumptive cost of electricity from a non-renewable energy source, which this Commission, in D.03-06-071, held to be a natural gas-fired baseload or peaker plant." (D.04-06-015, mimeo., p. 6, n.10.)

[7] Section 399.15(d)(3)

[8] Section 399.15(d)(4)

The MPR represents what it would cost to own and operate a baseload combined cycle gas turbine (CCGT) power plant over various time periods. The cost of electricity generated by such a power plant, at an assumed technical capacity factor and set of costs, is the proxy for the long-term market price of electricity established by this Commission. To ensure that the MPR represents "the value of different products including baseload, peaking, and as-available output,"[9] the IOUs apply their IOU-specific Time of Delivery (TOD)[10] profiles to the baseload MPR when evaluating RPS renewable facilities. The application of TOD factors to the MPR result in a market price for each product and generating unit.

In D.05-12-042, the methodology for calculating the MPR was expanded and stabilized. This methodology has been used for the resolutions calculating the MPR for 2005 and 2006. The 2007 MPR was calculated pursuant to D.07-09-024, wherein the Commission adopted an interim method to account for the costs of the emission of greenhouse gases (GHG adder).

D.07-09-024 authorized the use of the GHG adder for the 2007 MPR only. That decision also authorized an examination of the MPR for 2008 and later years, to determine whether any changes should be made to the MPR methodology, including how the compliance costs of State mandates to reduce GHG emissions should be reflected in the MPR.

In 2008, the Commission reevaluated the MPR methodology. This review resulted in a Commission decision that made several notable changes to the MPR methodology. Specifically, D.08-10-026 revised the MPR methodology for determining the cost of natural gas fuel, the capacity factor and the cost of compliance with greenhouse gas regulation for the MPR proxy plant. The decision also revised the methodology for calculating installed capital costs and transmission line losses and it permitted staff to calculate MPR values for a 25-year contract term.

[9] Section 399.15(c)(3).

[10] TOD factors are based on the forward value of electricity during different TOD periods. TOD factors for Pacific Gas and Electric Company, Southern California Electric Company and San Diego Gas & Electric are provided in Appendix B.

2009 MPRs were calculated using a cash-flow simulation model

Staff calculated the 2009 MPRs using the "MPR model", which is based on a cash-flow simulation methodology approved by the Commission.[11] The MPR model requires several types of input data, including natural gas prices, capital costs, operating costs, finance costs, taxes, and power delivery assumptions. The primary input drivers for the MPR calculation are the California (CA) gas price forecast, power plant capital costs, and the capacity factor for a proxy baseload plant. (Refer to 2009 MPR model, tabs; CA_Gas_Forecast, Install_Cap, and CF_Inputs.)

Release of 2009 MPR is consistent with prior Commission decisions

Pursuant to D.05-12-042, Staff is required to prepare a draft resolution for the annual MPR, including any relevant supporting materials as attachments to the draft resolution. The draft resolution is being released after all utility solicitations have closed. For 2009, the draft resolution incorporates the methodological changes adopted in the Commission's recent decision D.08-10-026 and updated inputs as necessary. Parties will have the usual opportunity to file comments and reply comments on the draft resolution prior to its formal consideration by the Commission.

DISCUSSION

2009 MPR Gas Methodology and Inputs

The most significant cost during the life a new CCGT is the cost of its natural gas fuel. The MPR models the cost of gas over the entire life of the proxy plant's long-term contract based on market prices and fundamental forecasts.

D.08-10-026 authorized Staff to use between nine and 12 years (the current maximum) of New York Mercantile Exchange (NYMEX) forward price data. In reviewing the applicable NYMEX data set,[12] Staff determined that there was no

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[11] A link to the 2009 MPR Model is provided on page 2 of this Resolution.

[12] The MPR Gas Methodology uses a 22-trading day average of NYMEX forward prices ending with the close of the utilities' solicitations. Accordingly, the 2009 MPR Fundamental Gas forecast is derived from NYMEX forward prices leading up to August 25, 2009.

evidence of a single outlier that would argue for using less than all available NYMEX forward prices. (Refer to 2009 model, "NYMEX_Futures" and "CA_Gas_Forecast" tabs.)

Comparison of 2009 MPR values to prior year's

The 2009 MPR values are lower than the 2008 MPRs. As discussed above, the most significant cost input during the life a new CCGT is the cost of its natural gas fuel. Fuel costs represent approximately 70 percent of a new CCGT's all-in costs. Record high natural gas prices during 2008 fueled higher MPRs for the 2008 RPS solicitations. Gas prices were relatively low in August 2009, resulting in lower 2009 MPRs.

Table 2: Comparison of 2008 and 2009 MPR NYMEX forward price data

NYMEX-year	$/MMBtu (2009 MPR)	$/MMBtu (2008 MPR)	Difference (%)
1	$5.89	$10.47	-43.7%
2	$6.73	$9.69	-30.5%
3	$6.91	$9.40	-26.4%
4	$7.02	$9.25	-24.1%
5	$7.15	$9.14	-21.8%
6	$7.30	$9.12	-20.0%
7	$7.44	$9.19	-19.0%
8	$7.59	$9.27	-18.1%
9	$7.74	$9.39	-17.5%
10	$7.89	$9.55	-17.3%
11	$8.04	$9.72	-17.3%
12	$8.19	$9.89	-17.3%

2009 MPR Installed Capital Data Set and Costs

Installed Capital Costs

Pursuant to Commission decisions, the MPR installed capital costs are derived from the publicly available cost data for the folowing CCGTs: Palomar (SDG&E), Cosumnes (SMUD) and Colusa (PG&E).[13] Based on the cost data for these plants, the average installed capital cost, reflecting interconnection costs, environmental permitting costs,[14] additional capacity costs for dry cooling, and contingency costs is $1,098/kw (Refer to 2009 MPR model "Installed_Cap" tab.)

Installed capital costs for Palomar and Colusa were escalated using Handy-Whitman's Index of Public Utility Construction Costs.[15] The 2009 MPR installed capital costs were escalated using a different Handy-Whitman index from the 2008 MPR calculation.[16] Specifically, staff used the "Total Steam Production Plant" index rather than "Total Other Production Plant." (Refer to 2009 MPR model "Installed_Cap" tab.) This change results in an approximate 2 percent decrease to the MPR value.

Capital Cost Inputs

The MPR model requires fixed and variable operational and maintenance (O&M) costs to calculate total installed capital costs for the MPR proxy CCGT. The 2008 MPR used CCGT O&M cost inputs from the California Energy Commission's Comparative Cost of Generation Report.[17] Staff retained the use of these O&M

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[13] See D.05-12-042 and D.08-10-026.

[14] This includes the environmental review and permitting costs incurred for a CCGT, including the purchase of emissions reduction offsets pursuant to California Health and Safety Code §§ 40709 and 40709.5.

[15] Whitman, Requardt & Associates, LLP publishes the Handy-Whitman Index of Public Utility Construction Costs.

[16] Handy-Whitman revised its recommendation to staff for which index is most appropriate for a CCGT.

[17] The fixed and variable O&M costs for CCGTs in this report are based on a survey of 19 plants built in California, nine of which began operating as recently as 2005 or 2006. *Comparative Cost of California Central Station Electricity Generation Technologies*, December

Footnote continued on next page

input values to calculate the 2009 MPR.[18] (Refer to 2009 MPR model "CF_Data_Set" tab.)

Explanation of MPR Environmental Inputs

GHG Compliance Cost

In D.08-10-026, the Commission made the cost of compliance with GHG regulation a permanent component of the MPR calculation. The decision adopted criteria for Staff to employ in modeling the GHG compliance costs incurred for the MPR proxy CCGT, prior to when California has a functioning GHG compliance market.[19]

Staff calculated the 2009 MPRs using $/$CO_2$ ton values based on Synapse Energy Economics' most recent report, "*Synapse 2008 CO_2 Price Forecasts*".[20] Specifically, Staff used the Synapse "mid-case" cost data, which assumes CO_2 prices of $15 in 2013, increasing to $30.80 in 2020 and $53.40 in 2030, which results in a levelized price of $30/ CO_2 ton in 2007$. Staff converted the reports $/$CO_2$ ton values, which are provided in 2007$, to nominal$ using a 2.5% inflation rate.[21] (Refer to 2009 MPR model "CF_Data_Set" tab; row 9.)

Table 3 identifies 2009 MPR GHG compliance costs for select years in short tons and its metric tonne (MT) equivalent.

2007. The report is available at: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF

[18] California Energy Commission staff are working on an update to this report but it has not been finalized as of the mailing date for this Resolution.

[19] The resource for modeling GHG compliance costs for the MPR should be: publicly available, based on multiple scenarios and sources of information, based on realistic and public assessments of policy proposals and scenarios, based on the most current reliable information that conforms to the other three criteria. (D.08-10-026, page 31)

[20] http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf

[21] Staff implemented the Synapse values in consultation with David White, one of the principal authors of the report, "*Synapse 2008 CO_2 Price Forecasts Report*".

CO_2 Conversion	2012	2015	2020
MPR GHG compliance cost in short tons (nominal$ / CO_2 ton)	**\$10.44/ CO_2 ton**	**\$24.35/ CO_2 ton**	**\$43.52/ CO_2 ton**
Conversion to Metric Ton (nominal$ /MT CO_2)	\$11.51/ MT CO_2	\$26.84/ MT CO_2	\$47.97/ MT CO_2

Emissions Reduction Offset Costs

In an ongoing effort to increase the transparency of the MPR inputs and assumptions, staff clarified the costs for the MPR proxy plant of obtaining emission reduction credits (ERC). The costs of ERCs have always been a component of the MPR installed capital costs, but these costs were not identified as a separate line item in previous MPRs. Staff's calculation of ERCs does not impact the MPR average installed capital cost value or the MPR values in any manner.

Staff derived the 2009 MPR ERC costs using the following methodology:[22]

1. Obtained criteria pollutant emissions in tons/year from the application for certification (AFC) filing for each plant (Palomar, Cosumnes, Colusa),
    a. converted emissions to tons/kW/year based on nameplate rating of each plant, and
    b. computed average tons/kw/year for three plants.
2. Sourced median ERC costs from "Emission Reduction Offsets Transaction Cost Report for 2007"[23] (California Environmental Protection Agency - Air Resources Board, Table 1, p. 2.)
    a. Excluded CO, for which offsets are not required in any district.

[22] Refer to 2009 MPR model, "Install_Cap" tab

[23] ERC costs vary widely allowing a small number of very high prices to skew average cost upward. In such cases it is common statistical practice to use median rather than average prices. http://www.arb.ca.gov/nsr/erco/ercrpt07.pdf

   b. Applied 1.2:1 offset ratio for all pollutants. Actual offset ratios vary by pollutant and by Air Quality Management District. 1.2 is commonly used as representative offset ratio in journal articles.
3. Multiplied ERC costs by tons/kw/year to calculate total $/kW ERC cost of $19/kW or $9.5 million for 500 MW MPR Proxy Plant.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

FINDINGS AND CONCLUSIONS

1. The 2009 MPRs were calculated and released consistent with Commission decisions.
2. The 2009 MPR values have been finalized for use in the 2009 Renewables Portfolio Standard solicitations.

THEREFORE IT IS ORDERED THAT:

1. The 2009 market price referents in Appendix A are approved for use in the 2009 Renewables Portfolio Standard solicitations.
2. This Resolution is effective today.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on December 17, 2009; the following Commissioners voting favorably thereon:

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Paul Clanon
Executive Director

Appendix A: Adopted 2009 Market Price Referents

Adopted 2009 Market Price Referents - Long-Term Contracts (Nominal - dollars/kWh)				
Contract Start Date	**10-Year**	**15-Year**	**20-Year**	**25-Year**
2010	0.08448	0.09066	0.09674	0.10020
2011	0.08843	0.09465	0.10098	0.10442
2012	0.09208	0.09852	0.10507	0.10852
2013	0.09543	0.10223	0.10898	0.11245
2014	0.09872	0.10593	0.11286	0.11636
2015	0.10168	0.10944	0.11647	0.12002
2016	0.10488	0.11313	0.12020	0.12378
2017	0.10834	0.11695	0.12404	0.12766
2018	0.11204	0.12090	0.12800	0.13165
2019	0.11598	0.12499	0.13209	0.13575
2020	0.12018	0.12922	0.13630	0.13994
2021	0.12465	0.13359	0.14064	0.14424

Adopted 2009 Market Price Referents - Short-Term Contracts (Nominal - dollars/kWh)					
Contract Start Date	**5-Year**	**6-Year**	**7-Year**	**8-Year**	**9-Year**
2010	0.07713	0.07881	0.08034	0.08178	0.08316
2011	0.08160	0.08307	0.08448	0.08583	0.08715
2012	0.08547	0.08684	0.08818	0.08950	0.09080
2013	0.08869	0.09007	0.09142	0.09276	0.09408
2014	0.09167	0.09309	0.09448	0.09586	0.09728
2015	0.09440	0.09586	0.09730	0.09878	0.10029
2016	0.09722	0.09872	0.10027	0.10186	0.10331
2017	0.10013	0.10177	0.10344	0.10495	0.10660
2018	0.10327	0.10503	0.10659	0.10834	0.11018
2019	0.10662	0.10824	0.11008	0.11203	0.11401
2020	0.10992	0.11187	0.11394	0.11604	0.11813
2021	0.11370	0.11591	0.11814	0.12035	0.12252

Appendix B: Utility's 2009 Time-of-Delivery (TOD) periods and factors

Pacific Gas and Electric[24]

Month	Period	Definition	Factor
June - September	Super-Peak	Hours Ending (HE) 13-20 Monday-Friday (except NERC holidays)	**2.20490**
	Shoulder	HE 7-12, 21 and 22 Monday-Friday (except NERC holidays); HE 7-22 Saturday, Sunday and all NERC holidays	**1.12237**
	Night	HE 1-6, 23 and 24 all days (including NERC holidays)	**0.68988**
October - February	Super-Peak	Defined above	**1.05783**
	Shoulder	Defined above	**0.93477**
	Night	Defined above	**0.76384**
March - May	Super-Peak	Defined above	**1.14588**
	Shoulder	Defined above	**0.84634**
	Night	Defined above	**0.64235**

24 PG&E 2009 RPS Solicitation, pro forma contract, pp. 45-46.
http://www.pge.com/includes/docs/word_xls/b2b/wholesaleelectricsuppliersolicitation/FinalAttH2009RPSPPA(amendedforSTOffers)(00084346).DOC

Southern California Edison Company[25]

Season	Period	Definition	Factor
Summer June 1 - September 30	On-Peak	WDxH[1], noon-6 pm	**3.13**
	Mid-Peak	WDxH, 8-noon, 6-11 pm	**1.35**
	Off-Peak	All other times	**0.75**
Winter October 1 - May 31	Mid-Peak	WDxH, 8 am-9 pm	**1.00**
	Off-Peak	WDxH, 6-8 am, 9 pm-midnight; WE/H[2] 6 am-midnight	**0.83**
	Super-Off-Peak	Midnight-6 am	**0.61**

1/ WDxH is defined as weekdays except holidays
2/ WE/H is defined as weekends and holidays

San Diego Gas &Electric[26]

Season	Period	Definition[1]	Factor
Summer July 1- October 31	On-Peak	Weekdays 11am-7pm	**1.6411**
	Semi-Peak	Weekdays 6am-11am; Weekdays 7pm-10pm	**1.0400**
	Off-Peak	All other hours	**0.8833**
Winter November 1 - June 30	On -Peak	Weekdays 1pm-9pm	**1.1916**
	Semi -Peak	Weekdays 6am-1pm; Weekdays 9pm-10pm	**1.0790**
	Off-Peak	All other hours	**0.7928**

1/ All hours during National Electric Reliability Council (NERC) holidays are Off-Peak.

[25] SCE 2009 RPS Solicitation, pro forma contract, Exhibit K, p. 2.
http://www.sce.com/NR/rdonlyres/4F174486-40D2-470B-AB23-96A3A583C2E5/0/20090629_RFP_Appendix_B1_ProForma_Agreement.doc

[26] SDG&E 2009 RPS Solicitation, pro forma contract, pp. 39-40.
http://www.sdge.com/documents/rfo/renewable2009/ModelPPA.doc

Appendix C: 2009 MPR California and Henry Hub Gas Forecast (2010 – 2046)

Year	2009 MPR Henry Hub Forecast (nominal$)	2009 MPR CA Gas Forecast (nominal$)
2010	$5.89	$6.20
2011	$6.73	$7.04
2012	$6.91	$7.24
2013	$7.02	$7.36
2014	$7.15	$7.50
2015	$7.30	$7.66
2016	$7.44	$7.81
2017	$7.59	$7.97
2018	$7.74	$8.13
2019	$7.89	$8.29
2020	$8.04	$8.45
2021	$8.19	$8.61
2022	$8.33	$8.87
2023	$8.59	$9.14
2024	$8.69	$9.17
2025	$9.14	$9.66
2026	$9.60	$10.14
2027	$10.00	$10.58
2028	$10.37	$10.99
2029	$10.74	$11.37
2030	$11.14	$11.78
2031	$11.48	$12.16
2032	$11.88	$12.57
2033	$12.26	$12.97
2034	$12.65	$13.37
2035	$13.04	$13.78
2036	$13.43	$14.19
2037	$13.83	$14.60
2038	$14.22	$15.02
2039	$14.62	$15.44
2040	$15.03	$15.86
2041	$15.44	$16.28
2042	$15.85	$16.71
2043	$16.26	$17.15
2044	$16.67	$17.58
2045	$17.09	$18.02
2046	$17.51	$18.46

Appendix D: 2009 MPR Natural Gas Fundamental Forecast Methodology

Background

The most significant cost during the life a new CCGT is the cost of its natural gas fuel. The MPR models the cost of gas over the entire life of the proxy plant's long-term contract. As the Commission pointed out in D.05-12-042, no new gas-fired plant in California actually enters into a 20-year fixed price contract for physical gas delivery. Therefore, in order to capture the "fixed-price fuel costs associated with fixed-price electricity from new generating facilities," the MPR model creates a forecast of long-term gas prices for purposes of the MPR. As explained in D.05-12-042, the MPR model is based on the fact that California market participants , when considering a power purchase agreement (PPA), "use some mixture of market data (NYMEX prices) and fundamentals forecasts for estimating long-term gas prices in a variety of settings, not only new PPAs for electricity produced from CCGTs".[27]

New York Mercantile Exchange (NYMEX) data

In D.05-12-042, the Commission authorized Staff to use all available NYMEX forward contract data, under this guidance, the 2005, 2006 and 2007 MPRs were calculated using the full six years of NYMEX. In 2008, NYMEX extended its forward gas contract term offering from six to 12 years. D.08-10-026 authorized Staff to use between nine and 12 years (the current maximum) of NYMEX forward price data.

Transition to Fundamental Forecast

The MPR model's long-term gas contract requires the use of fundamental gas forecasts to project gas prices when NYMEX forward prices are not available. The MPR fundamental forecast for years 12 – 25 was developed using an average of three out of four private sector natural gas forecasts (Henry Hub) from Cambridge Energy Research Associates, PIRA Energy Group, Global Insight or Wood Mackenzie. Due to contractual obligations requiring the Commission to keep the forecast confidential, Staff can not reveal which of the four firms the forecasts were purchased from.

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[27] D.05-12-042, p. 17.

The use of fundamental forecasts requires a two-step implementation process. First, a methodology must determine how to utilize the fundamental forecast data, and secondly, a methodology is required to transition from NYMEX data to fundamentals data.

D.08-10-026 directed Staff to make the transition from NYMEX forward prices to the first year of the MPR fundamental forecast by using a linear trend of the last three to five years of NYMEX forward prices, which mitigates the impact of any one price in the outer years of NYMEX. The first year of the MPR fundamental forecast is then extended using the annual escalation rate of the averaged private forecasts for the remainder of the MPR fundamental forecast.

California Basis Adjustment

Pursuant to D.08-10-026, Staff uses NYMEX Clearport prices for years when NYMEX data is used and California Basis data from private fundamental forecasts when the MPR Gas Methodology relies on private fundamental forecast data.

Staff continued its use of PG&E Citygate and SoCal Border Clearport prices for the first three years and then fixed the average price in year three through 2021, the last year when the MPR Gas Forecast relies on NYMEX forward prices.[28] The California Basis Adjustment for the remainder of the proxy CCGT's contract term is based on the average of basis prices from the private fundamental forecasts used to develop the long-term California MPR Gas Forecast. (Refer to 2008 MPR model "CA_Basis_Adj" tab.)

[28] NYMEX Clearport provides SoCal prices for up to six years; however, PG&E Citygate is only available for three; therefore, Staff determined it most reasonable to use the same methodology that was used in prior years.

Appendix E: 2009 MPR Gas Forecast Inputs

Row No.	Input Category	Input	Units	Baseload Inputs	Notes
1	Henry Hub Forecasts /1	CERA, PIRA, or Global Insight /2	$/MMBtu	N/A	20 yr. Henry Hub forecast (private - purchased)
2	General Inputs	Transaction Cost	$/MMBtu	$0.082	D.04-06-015, pg. 26, reafirmed in D.05-12-042 (pg. A-7)
3		Transportation Escalation Rate	Percent-%	2.04%	Average of EIA 2008 GDP Chain-Type Price Index. See 2008 MPR model - Delivery_Tar Tab (Cell E9)
4		20-year WACC	Percent-%	8.25%	2009 MPR model - Cost Cap Tab (Cell D9)
5	Municipal Surcharge	SoCal Muni Surcharge	Percent-%	1.462%	Schedule G-MSUR - http://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-MSUR.pdf
6		PG&E Muni Surcharge	Percent-%	0.913%	PG&E Rate Schedule GC-P: (1) http://www.pge.com/rates/tariffs/GCP_Current.xls and (2) http://www.pge.com/rates/tariffs/GSUR_Current.xls
7	PG&E Gas Distrib. Rate	Customer Access Charge	$/day	$182	http://www.pge.com/tariffs/pdf/G-EG.pdf
8		Proxy Plant Capacity	MW	500	2009 MPR model - Delivery_Tar Tab (Cell E15)
9		Heat Rate	MMBtu/MWh	6.88	2009 MPR model - Delivery_Tar Tab (Cell E16)
10		Capacity Factor	percent-%	92%	2009 MPR model - Delivery_Tar Tab (Cell E17)
11		Monthly Gas Consumption	MMBtu	75,750	(Row 8 * Row 9* Row 10) * 24 hours
12		Unit Cost of Customer Access Charge	$/MMBtu	$0.0024	Row 7 / Row 11
13		Transportation Charge	$/MMBtu	$0.1880	http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-EG.pdf
14	SoCal Gas Distrib. Rate	Customer Charge	$/month	$0.00000	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
15		Transmission Charge	$/MMBtu	$0.2273	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
16		Interstate Transportation Cost Surcharge	$/MMBtu	$0.0000	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf

1/ The Henry Hub forecasts are inputs for the MPR - Henry Hub forecast - there are no specific baseload values.

2/ Due to contractual obligations requiring the CPUC to keep the forecast confidential, staff can not reveal which of the three firms the forecast was purchased from.

Appendix F: 2009 MPR Non-Gas Inputs

Row No.	Input Category	Input	Units	Baseload Inputs	Escal. Rates/yr.	Notes
1	Capital Inputs	Total capital cost January 1 - 1st operational yr.	$/kw	$1,098	2.13%	Per D.05-12-042, Staff conducted a survey of actual plant costs in CA. Four plants were selected and an average was calculated
2		Fixed O&M	($/kW-yr) 1st operational yr.	$10.20	2.04%	CEC Cost of Generation Report CEC-200-2009-017-SD Table 22, p. 56
3		Variable O&M	(mills/kWh) 1st operational yr.	$4.74	2.04%	CEC Cost of Generation Report CEC-200-2009-017-SD Table 22, p. 56
4		New & Clean heat rate	Btu/kWh HHV	6704	n.a.	Per D.05-12-042, Staff used the the "new & clean" heat rate for an F-Series (GE S207FA) CC Turbine, adjusted for Higher Heating Value
5		Heat rate degradation factor	Percent-%	1.74%	n.a.	Per D.05-12-042, Staff contacted GE for an appropriate heat rate degradation factor for an F-series CC turbine. GE provide a degradtion curve that calculated the average degradation over the life of the project.
6		Average heat rate	Btu/kWh HHV	6924	n.a.	Average heat rate over life of plant, taking into account the impact of Higher Heating Value, degradation, dry cooling, and starts/stops
7	Finance Inputs	20-year WACC	Percent-%	8.25%	n.a.	Weight-Average Cost of Capital = (Cost of Equity x Equity %) + (Cost of Debt x (1-tax rate) x Debt %)
8		Cost of LT Debt	Percent-%	7.67%	n.a.	Per D.05-12-042, Cost of Debt (industrial firms) = risk free rate (20 year T-Bill) + risk premium (mid point between BBB & B+). http://www.bondsonline.com, May 13, 2008
9		Cost of Equity	Percent-%	11.96%	2.00%	Per D.05-12-042, Cost of Equity = risk free rate (20-yr Tbill) + risk premium (equity) + mid-cap risk premium (equity). http://www.bondsonline.com, May 13, 2008
10		Debt as % of total cost	Percent-%	50%	n.a.	Per D.05-12-042, LT debt ratio for BBB rated company
11		Debt Term	Years	20	n.a.	Adopted in D.04-06-015 and reaffirmed in D.05-12-042
12		Insurance as % of plant cost	Percent-%	0.60%	2.04%	Same value used for 2004 MPR. Energy Division contacted insurance brokers for quotes and calculated an average value.
13	Power Delivery Inputs	Transformer Loss Factor	Percent-%	0.50%	n.a.	Loss factor recommended by parties and used in 2004 MPR calculation
14		Generation Meter Multiplier (GMM) to load center	Percent-%	98.5%	n.a.	Not Used. Pursuant to D. 08-10-026, the MPR Model assumes delivery at the busbar
15		Capacity Factor	Percent-%	92%	n.a.	Per D.08-10-026
16	Tax Rate Inputs	Federal Tax Rate	Percent-%	35%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation
17		State Tax Rate	Percent-%	8.84%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation
18		Total Effective Tax Rate	Percent-%	40.75%	n.a.	Effective Tax = Federal Tax * (1 - State Tax) + State Tax
19		Property taxes as % of plant cost	Percent-%	1.20%	n.a.	Same value used for 2004 MPR. Energy Division averaged the property tax rates for 14 counties in which power plants were constructed (or under construction) in the last 5 years.
20	Gas Forecast	20yr gas forecast - 2010 levelized	$/MMBtu	$8.05	n.a.	Output from CA_Gas_Forecast Tab (Cell N42) in 2009 MPR model
21	GHG	GHG Compliance Cost	$/Ton	$15.00	n.a.	($15 in 2013). Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning. Synapse Energy Economics. March 2, 2007. Updated July 2008, Synapse 2008 CO2 Price Forecast (in $2007). (Table 2, p. 16) http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf